

<b>ANDROSCOGGIN ENERGY LIMITED</b>	)	<b>DEPARTMENT</b>
<b>LIABILITY COGENERATION CENTER</b>	)	<b>FINDINGS OF FACT AND ORDER</b>
<b>FRANKLIN COUNTY</b>	)	<b>AIR EMISSION LICENSE</b>
<b>JAY, MAINE</b>	)	
<b>A-718-71-A-N</b>	)	

After review of the air emission license application, staff investigation reports, and other documents in the applicant's file in the Bureau of Air Quality, pursuant to 38 M.R.S.A., Section 344 and Section 590, the Department finds the following facts:

# **I. REGISTRATION**

## **A. Introduction**

1. Androscoggin Energy LLC (AELLC) submitted an application for a new major source on September 12, 1997.
2. AELLC will be a nominally-rated 150 megawatt (MW) electric cogeneration plant utilizing three Westinghouse Model 251B12A combustion turbine generators followed by three duct burner-fired heat recovery steam generators (HRSGs) to produce superheated steam.
3. The AELLC will be located directly behind International Paper Company in Jay, Maine (IP Androscoggin Mill) on property leased from International Paper, will produce and sell electric power to IP Androscoggin Mill and others, as well as produce and sell steam to the IP Androscoggin Mill.

## **B. Emission Equipment to be Licensed**

### **Fuel Burning Equipment**

<b>Equipment</b>	<b>Licensed Capacity (MMBtu/hr)</b>	<b>Fuel Type, %Sulfur</b>	<b>Nominal Design Firing Rate</b>	<b>Stack #</b>
Turbine #1	675	Fuel Oil, 0.05%	4,821.4 gal/hr**	1
	675	Natural Gas	655.3 x10 <sup>3</sup> scf/hr*	
HRSG #1	304	Natural Gas	295.1 x10 <sup>3</sup> scf/hr*	

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Equipment	Licensed Capacity (MMBtu/hr)	Fuel Type, %Sulfur	Nominal Design Firing Rate	Stack #
Turbine #2	675	Fuel Oil, 0.05%	4,821.4 gal/hr**	2
	675	Natural Gas	655.3 x10 <sup>3</sup> scf/hr*	
HRSG #2	304	Natural Gas	295.1 x10 <sup>3</sup> scf/hr*	3
Turbine #3	675	Fuel Oil, 0.05%	4,821.4 gal/hr**	
	675	Natural Gas	655.3 x10 <sup>3</sup> scf/hr*	
HRSG #3	304	Natural Gas	295.1 x10 <sup>3</sup> scf/hr*	

\*Assuming 1030 Btu/scf

\*\*Assuming 0.14 MMBtu/gal

### C. Application Classification

A new source is considered major based on whether or not its maximum licensed allowed emissions exceed the "Significant Emission Levels" as given in Maine's Air Regulations. The future maximum licensed allowed emissions are as follows:

Pollutant	Future License	Sig.Level	PSD Level
	(TPY)	(TPY)	(TPY)
PM	83.91	100	25
PM <sub>10</sub>	83.91	100	15
SO <sub>2</sub>	54.53	100	40
NO <sub>x</sub>	362.00	100	40
CO	883.23	100	100
VOC	49.05	50	40

Therefore, the new source is major for all criteria pollutants except PM, PM<sub>10</sub>, SO<sub>2</sub>, and VOC. All criteria pollutant emissions associated with this new source are subject to Prevention of Significant Deterioration (PSD) review and Best Available Control Technology (BACT) requirements.

Franklin County has received a NO<sub>x</sub> waiver under the Clean Air Act Section 182(f) from the requirements to obtain NO<sub>x</sub> emission offsets or apply Lowest Achievable Emission Rates (LAER) for a new major source of NO<sub>x</sub> emissions.

## II. BEST PRACTICAL TREATMENT

### A. Introduction

In order to receive a license the applicant must control emissions from each unit to a level considered by the Department to represent best practical treatment (BPT), as defined in Chapter 100 of the Air Regulations. Separate control requirement

categories exist for new and existing equipment as well as for those sources located in designated non-attainment areas. Descriptions of the applicable requirements are provided below under the appropriate headings.

The AELLC facility is a cogeneration facility, which consists of the following major mechanical plant components:

- Three Westinghouse Model 251B12A combustion turbine generators sets. The combustion turbine units are designed to operate on natural gas or fuel oil.
- Three duct burner-fired Heat Recovery Steam Generators (HRSGs) utilizing horizontal gas flow and natural circulation. In order to conduct supplementary firing, each unit will employ a Low NO<sub>x</sub> design duct burner equipped to fire natural gas only.

Emissions are formed by the combustion of natural gas or fuel oil in the three turbine generator sets and the combustion of natural gas only in the three HRSG duct burners and are therefore addressed in the BACT analysis.

#### B. New Emission Units

BPT for new sources and modifications requires a demonstration that emissions are receiving Best Available Control Technology (BACT) as defined in Chapter 100 of the Air Regulations. BACT is a top down approach to selecting air emission controls considering economic, environmental and energy impacts.

Each of the three “Cogeneration Systems” will consist of a combustion turbine generator which will generate electricity and whose exhaust gases will be directed to a HRSG where steam will be generated. This facility will not have a condensing steam turbine-generator as compared to solely electrical generating gas turbine combined cycle facilities.

**Turbine #1, #2, and #3** are each approximately 50 MW combustion gas turbine generators, each rated at 675 MMBtu/hr heat input of natural gas or 675 MMBtu/hr heat input of fuel oil, with a maximum sulfur content not to exceed 0.05% by weight. The three turbines are subject to New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart GG - Standards of Performance for Stationary Gas Turbines, for which construction is commenced after October 3, 1977.

**40 CFR Part 60, Subpart GG** establishes the following emission limits: Pursuant to 40 CFR Part 60.333 SO<sub>2</sub> is limited to (a) 0.015% by volume @ 15% O<sub>2</sub> on a dry basis or (b) the fuel sulfur content shall not exceed 0.8% by weight.

Pursuant to 40 CFR Part 60.332(a)(1) NO<sub>x</sub> is limited based on the following equation:

$$\text{NO}_x - \text{STD} = 0.0075 * (14.4/Y) + F,$$

where STD is the allowable NO<sub>x</sub> emissions (percent by volume at 15% O<sub>2</sub> and on a dry basis), Y is a function of the manufacturer's rated load (kilojoules per watt hour), and F is a function of the fuel-bound nitrogen

Additionally, NSPS requires AELLC to monitor the fuel-bound nitrogen and sulfur content of the fuel for every bulk storage shipment, every 24 hours if there is no immediate bulk storage, or on an Administrator approved schedule. AELLC has proposed to seek approval from the Administrator to reduce the frequency of sampling.

NSPS also requires AELLC to continuously monitor and record the fuel consumption and the ratio of water to fuel being fired, if a water injection system is utilized for NO<sub>x</sub> emission control during oil firing.

**HRSGs #1, #2, and #3** are three steam generators, each equipped with a duct burner rated at 304 MMBtu/hr heat input of natural gas. The three HRSGs are subject to New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart D - Standards of Performance for Fossil-Fuel-Fired Steam Generators for which construction is commenced after August 17, 1971, and that has a heat input capacity of greater than 250 MMBtu/hr, and Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units which commences construction, modification, or reconstruction after June 19, 1984, and that has a heat input capacity of greater than 100 MMBtu/hr.

AELLC is not subject to New Source Performance Standards (NSPS), 40 CFR Part 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978 on the basis that for each HRSG no more than 33% of the potential electric output capacity and less than 25 MW electrical output will be supplied to any utility power distribution system for sale as found in 40 CFR Part 60.40a (b).

**40 CFR Part 60, Subpart D** establishes the following emission limits:

Pursuant to 40 CFR Part 60.42(a)(1) particulate matter is limited to 0.10 lb/MMBtu. Pursuant to 40 CFR Part 60.42(a)(2) no unit shall exhibit opacity greater than 20 percent opacity except for one six minute period per hour of not more than 27% opacity.

In addition, pursuant to 40 CFR Part 60.44(a) NO<sub>x</sub> is limited to 0.20 lb/MMBtu. Since the HRSGs will only fire natural gas a CEMS to monitor SO<sub>2</sub> and opacity is

not required pursuant to 40 CFR Part 60.45(b)(1). A CEMS to monitor NO<sub>x</sub> is also not required on the basis that AELLC shall take an emission limit of 0.14 lb/MMBtu which is 70% of the standard (0.20 lb/MMBtu) pursuant to 40 CFR Part 60.45(b)(3). Thus a diluent O<sub>2</sub> or CO<sub>2</sub> CEMS is not required pursuant to 40 CFR Part 60.45(b)(4).

**40 CFR Part 60, Subpart Db** establishes the following emission limits: Pursuant to 40 CFR Part 60.44b(i) NO<sub>x</sub> is limited to 0.20 lb/MMBtu on a 30 day rolling average basis. NSPS does not require AELLC to install, continuously monitor and record NO<sub>x</sub> and diluent O<sub>2</sub> or CO<sub>2</sub> emissions pursuant to 40 CFR Part 60.48b(i) and Part 60.47b(f).

Emissions from each Cogeneration System shall be vented through separate flues which discharge through three closely bundled stacks (1, 2, and 3) which will be 212 feet tall and represents Good Engineering Practice (GEP) formula height. The regulated pollutants emitted from the three Cogeneration Systems are particulate matter (PM), particulate matter with aerodynamic diameters smaller than ten micrometers (PM<sub>10</sub>), sulfur dioxide (SO<sub>2</sub>), nitrogen oxides (NO<sub>x</sub>), carbon monoxide (CO), and volatile organic compounds (VOC).

AELLC has proposed BACT for the Cogeneration Systems to be the following:

Turbine NO <sub>x</sub>	-	water injection during oil firing
Turbine NO <sub>x</sub>	-	Low NO <sub>x</sub> combustors
HRSG NO <sub>x</sub>	-	Low NO <sub>x</sub> burners
Turbine and HRSG NO <sub>x</sub>	-	Selective Catalytic Reduction during gas firing only
Turbine and HRSG SO <sub>2</sub>	-	the combustion of clean fuels
Turbine and HRSG CO	-	Catalytic Oxidation, Good Combustion Practices
Turbine and HRSG PM/PM <sub>10</sub>	-	Good Combustion Practices, combustion of clean fuels
Turbine and HRSG VOC	-	Catalytic Oxidation, Good Combustion Practices

A summary of the BACT analysis for each of the pollutants is discussed below.

1. PM and PM<sub>10</sub>  
AELLC identified baghouses, electrostatic precipitators, scrubbers, the combustion of clean fuels and good combustion practices as potential control technologies. However, add-on controls such as baghouses, electrostatic precipitators, and scrubbers were rejected as BACT based on the following

reasons: (1) add-on controls create unacceptable back pressure, thus reducing efficiency and increasing fuel usage; (2) due to the high level of excess air produced by combustion turbines the add-on control would be increased in size and cost, making them economically infeasible; and (3) the high level of excess air reduces pollutant concentrations, thus making the add-on control less effective. AELLC then further evaluated and has proposed the combustion of clean fuels and good combustion practices as BACT for particulate matter emissions from the combustion turbines and HRSGs.

2. SO<sub>2</sub>  
AELLC identified scrubbers and the combustion of clean fuels as potential control technologies. However, add-on controls such as scrubbers were rejected as BACT based on the same reasons stated previously. Thus, AELLC has proposed the combustion of clean fuels as BACT for sulfur dioxide emissions from the combustion turbines and HRSGs.

3. NO<sub>x</sub>  
AELLC identified the following as potential control technologies:
 

Turbine NO <sub>x</sub>	-	water injection during oil firing
Turbine NO <sub>x</sub>	-	Low NO <sub>x</sub> combustors
HRSG NO <sub>x</sub>	-	Low NO <sub>x</sub> burners
Turbine and HRSG NO <sub>x</sub>	-	selective catalytic reduction (SCR)
Turbine and HRSG NO <sub>x</sub>	-	selective non catalytic reduction (SNCR)
Turbine and HRSG NO <sub>x</sub>	-	good combustion practices

 Or any combination of the above.

NO<sub>x</sub> emissions are formed in the combustion process as a result of two mechanisms; first, by the conversion of a fraction of the chemically bound nitrogen within the fuel (called fuel-bound NO<sub>x</sub> - FBN) and second, by the oxidation of atmospheric nitrogen in the combustion flame (called thermal NO<sub>x</sub>). However, since there is relatively low nitrogen present in natural gas and distillate oil, the NO<sub>x</sub> emissions from FBN are generally considered to be insignificant. Consequently, NO<sub>x</sub> control technologies for gas turbines work to limit the formation of thermal NO<sub>x</sub>.

#### **Turbine and HRSG NO<sub>x</sub>**

##### **SCR**

SCR uses an ammonia injection system and a catalytic reactor to reduce NO<sub>x</sub>. An injection grid disperses NH<sub>3</sub> into the flue gas upstream of the catalyst and the NH<sub>3</sub> and NO<sub>x</sub> are reduced to nitrogen gas (N<sub>2</sub>) and water vapor (H<sub>2</sub>O) in the presence of the catalyst reactor. AELLC has proposed that the NO<sub>x</sub> emissions from the combustion turbines are predicted to be reduced to as low

as 6 ppmvd corrected to 15% O<sub>2</sub> with an SCR system depending on operating conditions.

In a gas turbine application, the temperature requirements of an SCR dictate placement of the SCR reactor within the HRSG. The temperatures must be maintained between 500-750 °F, to achieve the optimum ammonia/nitrogen ratio. AELLC has proposed that due to the variation in steam demands of the IP Androscoggin Mill, which will be met by the firing of the duct burners, maintaining this temperature window for the SCR system will be difficult and the reduction efficiency may not be achieved over the entire operating range of the system.

AELLC has proposed that when firing fuel oil, the SCR catalyst would oxidize a portion of the SO<sub>2</sub> in the flue gas to SO<sub>3</sub>. In addition, the CO oxidation catalyst upstream of the SCR would also oxidize SO<sub>2</sub> to SO<sub>3</sub>. The CO catalyst must be upstream of the SCR catalyst in order to prevent the ammonia from poisoning the catalyst and also to be located at the point of highest temperature to where CO reduction efficiencies are optimized. The SO<sub>3</sub> created would then react with the ammonia in the flue gas to form sulfuric acid mist (H<sub>2</sub>SO<sub>4</sub>) and ammonia salts. The formation of the ammonium salts would reduce the amount of ammonia available for reaction with the NO<sub>x</sub> thus reducing the control efficiency and requiring higher levels of ammonia injection. The ammonia salts would be released by the cogeneration systems as particulate matter. Therefore, based on the above AELLC has not proposed SCR ammonia injection during oil firing in the turbines.

#### **SNCR**

SNCR uses an ammonia injection system within a required temperature window to reduce NO<sub>x</sub> and NH<sub>3</sub> to nitrogen gas (N<sub>2</sub>) and water vapor (H<sub>2</sub>O). AELLC evaluated SNCR and rejected it as BACT on the basis that the required operating temperature window of 1600 - 2200 °F is not compatible with combustion turbine exhaust temperatures. Therefore, SNCR was determined to be not technically feasible.

#### **Turbine NO<sub>x</sub>**

##### **Dry Low NO<sub>x</sub> Combustors**

Dry Low NO<sub>x</sub> Combustor designs are based on the principle of lowering the reaction temperature of the combustion process and limiting the amount of excess air available during the combustion process. Dry Low NO<sub>x</sub> Combustors were determined by AELLC to be technically feasible and thus has proposed them as BACT. It should be noted that Dry Low NO<sub>x</sub> Combustors alone are not effective for reducing emissions when firing fuel oil

in the turbines. Thus AELLC evaluated water/steam injection during oil firing conditions.

#### Water/Steam Injection

An industry accepted method for abating thermal NO<sub>x</sub> formation during oil firing is to reduce the combustor flame temperature by introducing a thermal heat sink into the flame zone. Water or steam are effective at achieving this goal. Therefore, water injection was determined by AELLC to be technically feasible and was proposed as BACT during oil firing.

#### HRSG NO<sub>x</sub>

##### Low NO<sub>x</sub> Burners

Low NO<sub>x</sub> Burner designs are based on the principle of lowering the reaction temperature of the combustion process and limiting the amount of excess air available during the combustion process. Low NO<sub>x</sub> Burners were determined by AELLC to be technically feasible and were proposed as BACT for duct firing within the HRSGs.

#### Conclusion

In conclusion, AELLC has proposed to install a diluent water injection system within the turbines for oil firing conditions. The turbines shall have Dry Low-NO<sub>x</sub> Combustors and the duct burners of the HRSG shall have Low NO<sub>x</sub> Burners. In addition, an SCR system shall be located in the HRSG and operated during gas firing conditions. Finally, AELLC shall limit NO<sub>x</sub> emissions to the following as BACT:

Pollutant	Each Cogeneration System	Ave Time	Fuel Fired in Turbine
NO <sub>x</sub>	6 ppmvd @15% O <sub>2</sub>	24 hr block ave	gas
	42 ppmvd @15% O <sub>2</sub>	3 hr block ave	fuel oil

After 12 months from the date of initial performance testing, each Cogeneration System shall also demonstrate compliance with the following:

Pollutant	Each Cogeneration System	Ave Time	Fuel Fired in Turbine
NO <sub>x</sub>	4.5 ppmvd @15% O <sub>2</sub>	30 day rolling ave	gas

4. CO

AELLC identified and has proposed the utilization of an oxidation catalyst and good combustion practices as BACT for carbon monoxide emissions from the combustion turbines and HRSGs.

5. VOC

AELLC identified thermal oxidation, adsorption, condensation, catalytic oxidation, and good combustion practices as potential control technologies. However, thermal oxidation, adsorption and condensation have not been applied to combustion turbines or HRSGs, thus they were not considered as technologically feasible and rejected as BACT. AELLC then further evaluated and has proposed an oxidation catalyst and good combustion practices as BACT for volatile organic compound emissions from the combustion turbines and HRSGs.

Based on the above, the Department finds that the Cogeneration Systems #1, #2, and #3 shall meet BACT. In addition, the Department has determined that AELLC shall install a NH<sub>3</sub>, NO<sub>x</sub>, CO, and O<sub>2</sub> CEMS to monitor NH<sub>3</sub>, NO<sub>x</sub>, and CO emissions on the exhaust from each of the Cogeneration Systems #1, #2, and #3 as BACT.

### III. EMISSION STANDARDS

The following is a brief description of the origin of some of the emission limits which AELLC is subject to. In the situations where AELLC is subject to both a regulatory limit and a BACT or NSPS limit, the most stringent limit is listed within the order of this license and demonstration with that limit is considered to be a demonstration of the other limits.

A. Turbines #1, #2, and #3

1. Visible Emissions

a. Chapter 101

Visible emissions from each of the Turbines #1, #2, or #3 shall not exceed 40 percent opacity for more than 15 minutes in any continuous 3-hour period.

b. BACT

Visible emissions from each of the Turbines #1, #2, or #3 shall not exceed 20% opacity, measured as 6 minute averages, except for one 6 minute average period per hour of not more than 27% opacity.

2. Particulate Matter Emissions

a. Chapter 103

The Turbines #1, #2, and #3 shall each not exceed 0.06 lbs. particulate matter per million BTU.

b. BACT

see III.C. below

3. Low Sulfur Fuel

a. Chapter 106

AELLC shall not burn liquid fossil fuel containing over 2.0 percent sulfur by weight as fired in the Turbines #1, #2, and #3.

b. BACT

AELLC shall not burn liquid fossil fuel containing over 0.05 percent sulfur by weight as fired in the Turbines #1, #2, and #3.

4. Other Emission Limits:

a. SO<sub>2</sub>, NSPS 40 CFR Part 60.333(a) or (b)

AELLC shall (a) not exceed an SO<sub>2</sub> emission of 0.015% by volume @ 15% O<sub>2</sub> on a dry basis, or (b) shall not burn liquid fossil fuel containing over 0.8 percent sulfur by weight as fired in the Turbines #1, #2, and #3.

b. NO<sub>x</sub>, NSPS 40 CFR Part 60.332(a)(1)

AELLC shall not exceed a NO<sub>x</sub> emission from the Turbines #1, #2, and #3, based on the following equation:

$$\text{NO}_x\text{- STD} = 0.0075 * (14.4/Y) + F,$$

where STD is the allowable NO<sub>x</sub> emissions (percent by volume at 15% O<sub>2</sub> and on a dry basis), Y is a function of the manufacturer's rated load (kilojoules per watt hour), and F is a function of the fuel-bound nitrogen

c. BACT

see III.C. below

**B. Duct Burner Fired HRSGs #1, #2, and #3**

**1. Visible Emissions**

**a. Chapter 101**

Visible emissions from each of the duct burner fired HRSGs #1, #2, or #3 shall not exceed 40 percent opacity for more than 15 minutes in any continuous 3-hour period.

**b. 40 CFR Part 60.42(a)(b), BACT**

Visible emissions from each of the duct burner fired HRSGs shall not exceed 20% opacity, measured as 6 minute averages, except for one 6 minute average period per hour of not more than 27% opacity.

**2. Particulate Matter Emissions**

**a. Chapter 103**

The duct burner fired HRSGs #1, #2, and #3 shall each not exceed 0.06 lbs. particulate matter per million BTU.

**b. 40 CFR Part 60.42(a)(1)**

The duct burner fired HRSGs #1, #2, and #3 shall each not exceed 0.10 lbs. particulate matter per million BTU.

**c. BACT**

see III.C. below

**3. Low Sulfur Fuel**

**a. Chapter 106**

AELLC shall not burn liquid fossil fuel containing over 2.0 percent sulfur by weight as fired in the duct burner fired HRSGs #1, #2, and #3.

**b. BACT**

AELLC shall only fire natural gas in each of the duct burner fired HRSGs #1, #2, and #3.

**4. Other Emission Limits:**

**a. 40 CFR Part 60.44(a) and 40 CFR Part 60.44b(i)**

NO<sub>x</sub> from each of the duct burner fired HRSGs alone is limited to 0.20 lb/MMBtu.

**b. BACT**

NO<sub>x</sub> from each of the duct burner fired HRSGs alone is limited to 0.14 lb/MMBtu.

**c. BACT**

see III.C. below

**C. Cogeneration Systems #1, #2, and #3, BACT**

1. Emissions from the Cogeneration Systems #1, #2, and #3 shall not exceed the following limits, except during startup, shutdown, or fuel transfer, when firing natural gas in the HRSG and/or the Turbine:

Pollutant	Each Cogeneration System	Ave Time
NO <sub>x</sub>	6 ppmvd @15% O <sub>2</sub>	24 hr block ave

2. After 12 months from the date of initial performance testing, each Cogeneration System shall also demonstrate compliance with the following when firing natural gas in the HRSG and/or the Turbine:

Pollutant	Each Cogeneration System	Ave Time
NO <sub>x</sub>	4.5 ppmvd @15% O <sub>2</sub>	30 day rolling ave

3. Emissions from the Cogeneration Systems #1, #2, and #3 shall not exceed the following limits, except during startup, shutdown, or fuel transfer, when firing natural gas in the HRSG and/or firing fuel oil in the Turbine:

Pollutant	Each Cogeneration System	Ave Time
NO <sub>x</sub>	42 ppmvd @15% O <sub>2</sub>	3 hr block ave

4. Emissions from the Cogeneration Systems #1, #2, and #3 shall not exceed the following limits, depending on fuel type that is being fired in the respective Turbines, except during startup, shutdown, or fuel transfer when they shall not exceed III.C.5. below:

- a. When firing natural gas in the HRSG and/or the Turbine:

Pollutant	lb/hr	Ave Time
PM	6.27	--
PM <sub>10</sub>	6.27	--
SO <sub>2</sub>	1.35	--
NO <sub>x</sub>	24.37	24 hr block ave
CO	74.21	24 hr block ave

Firing Natural Gas In	VOC (lb/hr)
Turbine Only	2.13

Turbine & HRSG	5.17
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- b. When firing natural gas in the HRSG and/or firing fuel oil in the Turbine:

Pollutant	lb/hr	Ave Time
PM	24.21	--
PM <sub>10</sub>	24.21	--
SO <sub>2</sub>	32.38	--
NO <sub>x</sub>	133.25	24 hr block ave
CO	43.73	24 hr block ave

Firing Natural Gas In	VOC (lb/hr)
Turbine Only	8.00
Turbine & HRSG	11.04

5. Emissions from the Cogeneration Systems #1, #2, or #3 shall not exceed the following limits during startup, shutdown, or fuel transfer while firing natural gas or fuel oil, except for the first 12 months after the initial performance testing when they shall be exempt:

Pollutant	lb/hr	Ave Time
PM	24.21	--
PM <sub>10</sub>	24.21	--
SO <sub>2</sub>	32.38	--
NO <sub>x</sub>	133.25	24 hr block ave
CO	74.21	24 hr block ave
VOC	36.10	--

6. Emissions from the Cogeneration Systems #1, #2, and #3 shall each not exceed 0.06 lbs. particulate matter per million BTU.
7. Visible emissions from each of the Cogeneration Systems #1, #2, or #3 shall not exceed 20% opacity, measured as 6 minute averages, except for one 6 minute average period per hour of not more than 27% opacity.
8. Emissions from the duct burner fired HRSGs #1, #2, and #3 alone shall each not exceed 0.14 lbs. nitrogen oxides per million BTU.

D. Facility Emissions

Facility emissions are based on a facility fuel use limit of:

1. 11,180,000 gallons/year of fuel oil with a maximum sulfur content not to exceed 0.05% by weight within the three turbines and the remaining time firing natural gas at maximum capacity; and
2. 2,637.2 x10<sup>6</sup> standard cubic feet per year of natural gas for the three HRSGs.

**Total Allowable Annual Emissions for the Facility**  
(used to calculate the annual license fee)

Pollutant	TPY
PM	83.91
PM <sub>10</sub>	83.91
SO <sub>2</sub>	54.53
NO <sub>x</sub>	362.00
CO	883.23
VOC	49.05

**IV. AMBIENT AIR QUALITY ANALYSIS**

**A. Overview**

A combination of screening and refined modeling was performed to show that the proposed Androscoggin Energy Limited Liability Company Cogeneration facility (AELLC) emissions, in conjunction with other sources, would not cause or contribute to violations of Maine Ambient Air Quality Standards (MAAQS) for SO<sub>2</sub>, PM<sub>10</sub>, NO<sub>2</sub>, and CO, or to Class I or Class II increments for SO<sub>2</sub>, PM<sub>10</sub> and NO<sub>2</sub>.

Since AELLC is entirely increment consuming and the nearest Class I area is approximately 83 kilometers away, Class I and II SO<sub>2</sub>, PM<sub>10</sub> and NO<sub>2</sub> increment analyses were performed. In addition, analyses were performed to show that AELLC's emissions will not adversely impact other Class I and II air quality related values (AQRV's).

**B. Model Inputs**

The SCREEN3 model was used to determine the worst case operating loads in all areas. The ISCST3 model using sequential meteorological data and a network of receptors was used to address standards in simple terrain (terrain with elevations at or below the stack top elevation). The CTSCREEN model was used to address standards in all intermediate and complex terrain (terrain with elevations above the stack top elevation). Sequential ISCST3 modeling, in simple and complex terrain mode, using all five (5) years (1988-1992) of meteorological data was performed for the combined source NO<sub>2</sub> MAAQS and increment compliance demonstrations. In addition, sequential ISCST3 and CALPUFF modeling, in

simple and complex terrain mode, using 1 year (1993) of meteorological data was performed for Class I increment and deposition analyses.

All modeling was performed in accordance with all applicable requirements of the Maine Department of Environmental Protection, Bureau of Air Quality (MEDEP-BAQ) and the United States Environmental Protection Agency (USEPA).

A valid five (5)-year (1988-1992) hourly on-site meteorological data bases was used for the sequential ISCST3 modeling. A sixth year (1993) was used for sequential ISCST3 increment and dry deposition modeling for the Great Gulf Wilderness Area/Dry River - Presidential Range Class I area. The on-site 91-meter meteorological monitoring tower, maintained by the International Paper Company (IP) since 1981, supports instruments at two levels: 91-meters and 10-meters. All six years of meteorological data had individual and joint recovery rates greater than the required 90% level. Data substitution schemes and stability determinations met all applicable requirements of MEDEP-BAQ and EPA.

A single year (1993) of meteorological data from three surface stations (Jay, Portland and Bangor), one upper air station (Portland NWS) and six precipitation stations (Jay, Portland, Augusta, Orono, Skowhegan, and Acadia National Park) was used to develop the CALPUFF wind fields and other meteorological information.

Stack parameters used in the modeling for the proposed AELLC facility, as well as off-site sources, are listed in Table IV-1. The modeling analyses accounted for the potential for building wake effects on emissions from the modeled stacks that are below their respective formula GEP stack height.

**Table IV-1. Stack Parameters**

Facility/ Stack	Stack Base Elev. (m)	Stack Ht. (m)	GEP Stack Ht. (m)	Stack Dia. (m)	UTM E (km)	UTM N (km)
<b>Part A Future/Current</b>						
<b>Androscoggin Energy LLC (AELLC), Jay (Future)</b>						
Flue A, B or C	131.06	64.62	60.95	3.424	401.2458	4928.6295
Combined Flues	131.06	64.62	60.95	5.931	401.2458	4928.6295
<b>International Paper Company, Jay</b>						
Power Boilers 1 and 2	125.27	91.40	105.92	3.81	401.444	4928.617
Waste Fuel Incinerator	125.27	67.21	105.92	2.74	401.461	4928.589
Recovery Furnaces 1 and 2	125.27	73.20	105.92	4.57	401.519	4928.567
Smelt Dissolving Tank 1	125.27	51.10	105.92	1.52	401.511	4928.592
Smelt Dissolving Tank 2	125.27	53.30	105.92	1.52	401.509	4928.562
Lime Kiln 1	125.27	30.50	102.12	1.37	401.631	4928.459

**ANDROSCOGGIN ENERGY LIMITED )**  
**LIABILITY COGENERATION CENTER )**  
**FRANKLIN COUNTY )**  
**JAY, MAINE )**  
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Lime Kiln 2	125.27	30.50	105.92	1.60	401.616	4928.441
Flash Dryers						
Point FD1A	124.97	11.90	105.92	1.37	401.440	4928.767
Point FD1B	124.97	11.90	105.92	1.37	401.430	4928.755
Point FD2	124.97	18.90	105.92	1.07	401.423	4928.769
<b>Otis Specialty Papers, Jay</b>						
Otis Specialty Papers	108.20	60.96	59.30	2.08	404.710	4925.610
<b>Northeast Limited Energy Partnership #1, Livermore Falls</b>						
NELP#1	121.92	67.10	85.65	2.44	407.470	4920.400
<b>Specialty Minerals, Inc., Jay</b>						
4 co-located stacks	125.30	18.29	105.92	0.61	401.631	4928.459
<b>Part B NO<sub>2</sub> Baseline</b>						
<b>International Paper Company, Jay (1986 Baseline)</b>						
Power Boilers 1 and 2	125.27	91.40	105.92	3.81	401.444	4928.617
Waste Fuel Incinerator	125.27	60.96	105.92	2.74	401.461	4928.589
Recovery Furnaces 1 and 2	125.27	73.20	105.92	4.57	401.519	4928.567
Lime Kiln 1	125.27	18.30	104.40	1.50	401.631	4928.459
Lime Kiln 2	125.27	30.50	104.40	1.60	401.616	4928.441
Flash Dryers						
Point FD1A	124.97	11.90	105.92	1.37	401.440	4928.767
Point FD1B	124.97	11.90	105.92	1.37	401.430	4928.755
Point FD2	124.97	18.90	105.92	1.07	401.423	4928.769
<b>Otis Specialty Papers, Jay (1986 Baseline)</b>						
Otis Specialty Papers	108.2	60.96	59.30	3.66	404.710	4928.610

Emission parameters for AELLC's limiting operating load cases and off-site sources used in demonstrating compliance with MAAQS and increment are listed in Table IV-2. The operating loads and seasonal conditions were evaluated using natural gas and No.2 fuel oil firing for the combustion turbines and natural gas firing for the duct burners. For the purpose of determining NO<sub>2</sub> and PM<sub>10</sub> impacts, all NO<sub>x</sub> and PM emissions were conservatively assumed to convert to NO<sub>2</sub> and PM<sub>10</sub>, respectively.

**Table IV-2. Emission Parameters**

Facility / Stack (Operating Scenario)	Averaging Period(s)	SO <sub>2</sub> (g/s)	PM <sub>10</sub> (g/s)	NO <sub>2</sub> (g/s)	CO (g/s)	Temp (K)	Stack Vel. (m/s)
<b>Part A Future/Current</b>							
<b>AELLC, Jay (Future)</b>							
100% Winter Combined	ALL	8.32	6.892	36.22	11.38	421.5	24.52
65% Winter Combined	ALL	6.27	6.892*	24.37	16.45	421.5	17.44
100% Natural Gas-Winter	ALL	0.48	2.376	7.98	5.58	394.8	22.84
100% Natural Gas-Average	ALL	0.51	1.98	22.17#	5.37	394.3	21.45
65% Natural Gas-Winter	ALL	0.39	1.83	31.26#	16.29	393.2	16.15

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50% Natural Gas-Winter	ALL	0.33	1.83	34.59#	28.05	393.2	14.77
<b>International Paper Company, Jay (Maximum Allowed)</b>							
Power Boilers 1 and 2	Annual	n/a	n/a	65.33	n/a	485	19.26
Waste Fuel Incinerator	Annual	n/a	n/a	22.59	n/a	339	14.50
Recovery Furnaces 1 and 2	Annual	n/a	n/a	26.88	n/a	479	16.31
Lime Kiln 1	Annual	n/a	n/a	4.20	n/a	346	8.94
Lime Kiln 2	Annual	n/a	n/a	4.20	n/a	349	10.33
Flash Dryers							
Point FD1A	Annual	n/a	n/a	0.672	n/a	394	16.61
Point FD1B	Annual	n/a	n/a	0.672	n/a	394	16.61
Point FD2	Annual	n/a	n/a	0.168	n/a	311	3.43
<b>Otis Specialty Papers, Jay</b>							
Otis Specialty Papers	Annual	n/a	n/a	11.26	n/a	450	19.18
<b>Specialty Minerals, Inc., Jay</b>							
4 co-located stacks	Annual	n/a	n/a	3.024	n/a	344	13.26
<b>Northeast Limited Energy Partnership #1, Livermore Falls</b>							
NELP#1	Annual	n/a	n/a	10.09	n/a	439	21.94
<b>Part B NO<sub>2</sub> Baseline</b>							
<b>International Paper Company, Jay (1986 Baseline)</b>							
Power Boilers 1 and 2	Annual	n/a	n/a	33.66	n/a	469	11.42
Waste Fuel Incinerator	Annual	n/a	n/a	8.42	n/a	449	14.06
Recovery Furnaces 1 and 2	Annual	n/a	n/a	18.50	n/a	470	12.12
Lime Kiln 1	Annual	n/a	n/a	2.79	n/a	346	5.54
Lime Kiln 2	Annual	n/a	n/a	2.79	n/a	349	5.81
Flash Dryers							
Point FD1A	Annual	n/a	n/a	0.236	n/a	394	16.61
Point FD1B	Annual	n/a	n/a	0.236	n/a	394	16.61
Point FD2	Annual	n/a	n/a	0.059	n/a	311	3.43
<b>Otis Specialty Papers, Jay (1986 Baseline)</b>							
Otis Specialty Papers	Annual	n/a	n/a	4.75	n/a	425	1.57

Notes:

- \* PM<sub>10</sub> modeled emission rate shown is greater than the emission rate that will occur with the 65% load condition
  - # NO<sub>2</sub> modeled emission rates for these operating scenarios are higher than the proposed SCR NO<sub>2</sub> emission rates.
- n/a Not Applicable

C. Applicant's modeled impacts

SCREEN3 simple and complex terrain screening analyses were performed for the various AELLC alone operating load cases representing 100%, 75%, 65%, and 50% for natural gas firing and 100%, 75% and 65% for No. 2 oil firing for three ambient temperature conditions (12°F (winter), 45°F (average) and 89°F (summer)). Results are summarized in Table IV-3. It was demonstrated that the 100% winter No. 2 oil firing operating load case resulted in maximum impacts for all SO<sub>2</sub> and PM<sub>10</sub> averaging periods and the 65% winter No. 2 oil firing operating load case resulted in the highest annual NO<sub>2</sub> impact. When using natural gas, the

100% winter operating load case resulted in maximum impacts for all SO<sub>2</sub> and PM<sub>10</sub> averaging periods and the 50% winter operating load case resulted in the highest annual NO<sub>2</sub> impact.

When No. 2 fuel oil was used, significance levels were exceeded for all pollutant averaging periods except for 1-hour and 8-hour CO averaging periods. When natural gas was modeled, significance levels were exceeded only in intermediate/complex terrain for the annual NO<sub>2</sub> and annual PM<sub>10</sub> averaging periods. Therefore, further analysis of all CO averaging periods will not be required.

**TABLE IV-3. AELLC Alone Worst Case Load Predicted Impacts**

Pollutant/ Averaging Period	Worst Case Operating Scenarios	NAT. GAS SCREEN3 Simple Terrain Impact (µg/m <sup>3</sup> )	NAT. GAS SCREEN3 Complex Terrain Impact (µg/m <sup>3</sup> )	OIL SCREEN3 Simple Terrain Impact (µg/m <sup>3</sup> )	OIL SCREEN3 Complex Terrain Impact (µg/m <sup>3</sup> )	SIG. LEVEL (µg/m <sup>3</sup> )
SO <sub>2</sub> 3-hr	100% average	0.68	<u>2.31</u>	14.71	<b>50.11</b>	<b>25</b>
	100% winter	0.59	2.11	15.03	<u><b>53.76</b></u>	
	65% winter	<u>0.70</u>	1.97	<u>16.36</u>	<b>46.42</b>	
SO <sub>2</sub> 24-hr	100% average	0.30	<u>0.64</u>	<b>6.54</b>	<b>13.92</b>	<b>5</b>
	100% winter	0.26	0.59	<b>6.68</b>	<u><b>14.93</b></u>	
	65% winter	<u>0.31</u>	0.55	<u><b>7.27</b></u>	<b>12.89</b>	
SO <sub>2</sub> Annual	100% average	<u>0.06</u>	<u>0.20</u>	<b>1.31</b>	<b>4.45</b>	<b>1</b>
	100% winter	0.05	0.19	<b>1.34</b>	<u><b>4.78</b></u>	
	65% winter	0.06	0.17	<u><b>1.45</b></u>	<b>4.13</b>	
PM <sub>10</sub> 24-hr	100% average	1.81	<u>3.83</u>	<b>9.45</b>	<b>20.13</b>	<b>5</b>
	100% winter	1.68	3.75	<b>9.58</b>	<u><b>21.41</b></u>	
	65% winter	<u>2.10</u>	3.70	<u><b>10.28</b></u>	<b>18.23</b>	
PM <sub>10</sub> Annual	100% average	0.36	<u><b>1.22</b></u>	<b>1.89</b>	<b>6.44</b>	<b>1</b>
	100% winter	0.34	<b>1.20</b>	<b>1.92</b>	<u><b>6.85</b></u>	
	65% winter	<u>0.42</u>	<b>1.19</b>	<u><b>2.06</b></u>	<b>5.83</b>	
NO <sub>x</sub> Annual	100% average	<b>2.62</b>	<b>8.91</b>	<b>5.53</b>	<b>18.83</b>	<b>1</b>
	100% winter	<b>2.51</b>	<b>8.99</b>	<b>5.50</b>	<b>19.66</b>	
	65% winter	<b>4.96</b>	<b>14.01</b>	<u><b>7.75</b></u>	<u><b>21.99</b></u>	
	50% winter	<u><b>5.89</b></u>	<u><b>15.92</b></u>	nm	nm	
CO 1-hr	50% winter	<u>35.81</u>	<u>96.81</u>	<u>19.60</u>	<u>55.61</u>	<b>2000</b>
CO 8-hr	50% winter	<u>25.07</u>	<u>67.76</u>	<u>13.72</u>	<u>38.93</u>	<b>500</b>

Note:

nm not modeled.

Sequential ISCST3 modeling, in simple terrain mode, using all five (5) years of meteorological data was performed for the following AELLC alone operating load cases:

- 1 100% Winter Combined
  - 2 combustion turbines firing No. 2 fuel oil in a 100% winter condition
  - 1 combustion turbine firing natural gas in a 100% winter condition
  - 3 duct burners firing natural gas
- 2 65% Winter Combined
  - 2 combustion turbines firing No. 2 fuel oil in a 65% winter condition
  - 1 combustion turbine firing natural gas in a 65% winter condition
  - 3 duct burners firing natural gas
- 3 50% Winter Natural Gas
  - 3 combustion turbines firing natural gas in a 50% winter condition
  - 3 duct burners firing natural gas

Results are summarized in Table IV-4. Significance levels were not exceeded for any pollutant averaging period, therefore, further analyses of SO<sub>2</sub>, PM<sub>10</sub> and NO<sub>2</sub> impacts in simple terrain for all operating load cases will not be required.

**TABLE IV-4. Maximum AELLC Alone Predicted Impacts in Simple Terrain**

Pollutant/ Averaging Period	Max ISCST3* Impact (µg/m <sup>3</sup> )	Operating Scenario	Receptor UTM-E (km)	Receptor UTM-N (km)	Receptor Elevation (m)	Class II Significance Level (µg/m <sup>3</sup> )
SO <sub>2</sub> 3-hr	4.10	100% Winter Combined	401.250	4927.850	158.50	25
SO <sub>2</sub> 24-hr	1.45	100% Winter Combined	402.050	4928.250	115.82	5
SO <sub>2</sub> Annual	0.07	65% Winter Combined	405.400	4926.500	192.02	1
PM <sub>10</sub> 24-hr	1.52	65% Winter Combined	402.050	4928.250	115.82	5
PM <sub>10</sub> Annual	0.08	65% Winter Combined	405.400	4926.500	192.02	1
NO <sub>x</sub> Annual	0.62**	50% Natural Gas-Winter	405.400	4926.500	192.02	1

Notes:

\* simple terrain mode

\*\* NO<sub>2</sub> conservative modeled emission rate for this operating scenario is higher than the proposed SCR NO<sub>2</sub> emission rate.

CTSCREEN modeling in terrain above stack top elevations was performed for the 100% and 65% winter combined fuel operating load cases. Results are summarized in Table IV-5. Significance levels were only exceeded for the annual NO<sub>2</sub> averaging period, therefore, further analyses of SO<sub>2</sub> and PM<sub>10</sub> impacts in intermediate and complex terrain for all operating load cases was not required.

**TABLE IV-5. Maximum AELLC Alone CTSCREEN Predicted Impacts**

Pollutant/ Averaging Period	Max CTSCREEN Impact ( $\mu\text{g}/\text{m}^3$ )	Operating Scenario	Receptor UTM-E (km)	Receptor UTM-N (km)	Receptor Elevation (m)	Class II Significance Level ( $\mu\text{g}/\text{m}^3$ )
SO <sub>2</sub> 3-hr	20.62	100% Winter Combined	398.750	4929.200	224.0	25
SO <sub>2</sub> 24-hr	4.42	100% Winter Combined	398.750	4929.200	224.0	5
SO <sub>2</sub> Annual	0.88	100% Winter Combined	398.750	4929.200	224.0	1
PM <sub>10</sub> 24-hr	4.40	65% Winter Combined	398.750	4929.200	224.0	5
PM <sub>10</sub> Annual	0.88	65% Winter Combined	398.750	4929.200	224.0	1
NO <sub>x</sub> Annual	<b>3.85</b>	100% Winter Combined	398.800	4929.200	224.0	1

#### D. Combined Source Modeling

Because the modeled impact from the AELLC facility was greater than the significance level for the annual NO<sub>2</sub> averaging period, other sources not explicitly included in the modeling analysis must be accounted for by using a representative background concentration for the area. An annual NO<sub>2</sub> averaging period background concentration of 26  $\mu\text{g}/\text{m}^3$  was used based on conservative urban background Portland PEOPLE site monitoring data reported by the MEDEP-BAQ Field Services Division.

MEDEP-BAQ identified other sources whose impacts would potentially be significant in the AELLC significant impact area. The other sources included in the final compliance demonstration included IP, Otis Specialty Papers (OTIS) and Specialty Minerals Inc. located in Jay and Northeast Energy Limited Partnership #1 (NELP#1) located in Livermore Falls.

The ISCST3 model, in simple and complex mode, using the five (5) year meteorological database, was used to determine the combined source maximum annual NO<sub>2</sub> impact. As suggested in Section 6.2.3 of Appendix W to 40 CFR Part 51 "Guideline On Air Quality Models" ([Guideline](#)), a multi-tiered approach for estimating annual NO<sub>2</sub> impacts was used. Tier 1 assumes total conversion of NO<sub>x</sub> to NO<sub>2</sub>. Tier 2 which uses an empirically derived NO<sub>2</sub>/NO<sub>x</sub> ratio of 0.75 (annual national default) is shown in Table IV-6 for the maximum combined source annual NO<sub>2</sub> impact. Results of the Tier 2 approach was then added to background. Results of this approach, as shown in Table IV-6, shows compliance with annual NO<sub>2</sub> MAAQS.

**Table IV-6. Maximum Combined Source Predicted Impacts**

Pollutant/ Averaging Period	Max ISCST3 Impact* ( $\mu\text{g}/\text{m}^3$ )	Receptor UTM-E (km)	Receptor UTM-N (km)	Receptor Elevation (m)	Background ( $\mu\text{g}/\text{m}^3$ )	Max Total Impact ( $\mu\text{g}/\text{m}^3$ )	MAAQS ( $\mu\text{g}/\text{m}^3$ )
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NO <sub>2</sub> Annual Tier 2	27.46	402.500	4929.500	188.98	26	53.46	100
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Note:

\* simple and complex terrain mode

#### E. Class II Increment

In accordance with requirements of Chapters 115 and 140 of the DEP regulations, both major and minor sources in the applicant's significant impact area need to be considered in the increment analysis for a major new source. The increment analysis shall include air quality impacts and nature and extent of any or all general, commercial, residential, industrial and other growth, including increases in mobile source and area source emissions that has occurred since the baseline date and therefore have consumed increment in the area where the source will significantly impact.

Table IV-7 summarizes AELLC's and combined source NO<sub>2</sub> increment impacts in Class II areas using the same approach used in the MAAQS compliance demonstration. Results, as shown in Table IV-7, shows compliance with the annual NO<sub>2</sub> Class II increment using the Tier 2 approach.

**Table IV-7. Increment Consumption in Class II Areas from AELLC plus Other Sources**

Pollutant/ Averaging Period	Max AELLC Impact* (µg/m <sup>3</sup> )	Max Combined Source Impact** (µg/m <sup>3</sup> )	Receptor UTM-E (km)	Receptor UTM-N (km)	Receptor Elevation (m)	Class II Increment (µg/m <sup>3</sup> )
NO <sub>2</sub> Annual Tier 2	2.89	na	398.800	4929.200	224.0	25
NO <sub>2</sub> Annual Tier 2	na	20.12	402.500	4929.500	188.98	25

Notes:

na Not applicable

\* Maximum of ISCST3 (simple terrain mode) and CTSCREEN impacts

\*\* Maximum ISCST3 (simple and complex terrain mode) impact

**GENERAL GROWTH:** Some increases in local emissions due to construction related activities are expected to occur for approximately 18 months. Emissions of dust from construction related activities will be minimized by the use of Best Management Practices for construction on site. Increases in potential emissions of NO<sub>x</sub> due to commuting by construction workers will be temporary and short-lived.

**RESIDENTIAL GROWTH:** Population growth in the impact area of the proposed source can be used as a surrogate factor for the growth in emissions

from residential combustion sources. AELLC is expected to create approximately 15 new full-time jobs as a result of this proposed project. However, it is expected that the available local work force will be able to fill in some of these positions. Thus, no new significant residential growth will follow from this new source. Also, the presence of a natural gas line to the Town of Jay will have the potential to make gas available for future residential use and thereby reduce the reliance on less clean fuels.

**COMMERCIAL GROWTH:** No significant commercial growth is expected to occur as a result of this project.

**INDUSTRIAL GROWTH:** As a result of the creation of approximately 15 new permanent jobs at the proposed facility there will be a minor increase in worker traffic. There will be no regular truck traffic associated with the cogeneration facility operation aside from limited deliveries of process consumables. Also, as a result of the operation of the cogeneration facility, the IP mill will reduce the number of No. 6 fuel oil trucks to the mill. It is expected that there will be a net decrease in vehicular NO<sub>x</sub> emissions due to the project.

**MOBILE SOURCE AND AREA SOURCE GROWTH:** Since area and mobile sources are considered minor sources of NO<sub>2</sub>, their contribution to increment has to be evaluated. Technical guidance from the Environmental Protection Agency points out that screening procedures can be used to determine whether detailed analyses of minor source emissions are required. A minor source inventory may not be required if it can be shown that little or no growth has taken place in the impact area of the proposed source since the minor source baseline date (February 8, 1988) was established. Emissions during the calendar year 1987 are used to determine baseline emissions. Using U.S. Bureau of the Census population estimate programs, the population growth in the Jay area is projected to increase from 5,080 in 1990 to 5,487 in 1996. An increase of 400 people on an absolute scale represents a small increase in population. Therefore, this level of population growth is considered insignificant and no further assessment of additional area source growth on the NO<sub>2</sub> increment is needed.

The NO<sub>2</sub> emissions associated with mobile traffic are difficult to quantify for the purpose of determining minor source increment consumption. Data from the Maine Department of Transportation (DOT) indicates that vehicle mile traveled (VMT) for the roads surrounding Jay, Maine have decreased from 1991 to 1996. Therefore, the reduction in VMT and the gradual retirement of older, higher polluting automobiles means that from the 1987 NO<sub>2</sub> baseline date, an expansion of NO<sub>2</sub> increment has likely occurred. Therefore, since there has been no increase

in actual NO<sub>2</sub> emissions from mobile sources, any further detailed analyses of mobile NO<sub>2</sub> emissions are not needed.

F. Additional Class II Impact Analyses

Chapters 115 and 140 of MEDEP regulations requires that the applicant for any major new source provide an additional impact analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source and general, commercial, residential, industrial and other growth associated with the source.

**VISIBILITY:** Class II visible emissions from the proposed facility will be minimized by controlling emissions through the implementation of BACT which includes the combustion of clean fuels (i.e. low sulfur oil and natural gas).

**SOILS AND VEGETATION:** Impacts on sensitive vegetation and soils were evaluated using the maximum impacts from the ISCST3 and CTSCREEN modeling analyses. The results of the soil and vegetation impacts are shown in Table IV-8. Evaluation of impacts on sensitive vegetation and soils was performed by comparison of predicted facility impacts with screening levels presented in *A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals* (EPA, December, 1980, EPA 450/2-81-078). Any acute or chronic deleterious effects to the soils and vegetation would be expected to occur only at ambient concentration levels substantially higher than impacts predicted by dispersion modeling. Proposed emissions from AELLC's proposed facility are not expected to impact even the more sensitive soil or vegetation near the facility. Because the soil and vegetation impacts near the facility (non-Class I areas) are well below the vegetation sensitivity levels, impacts in Class I areas were not evaluated.

**TABLE IV-8. Soil and Vegetation Impacts, AELLC Alone**

Pollutant	Averaging Period	Max AE Class II Impact ( $\mu\text{g}/\text{m}^3$ )	Sensitivity Screening Levels ( $\mu\text{g}/\text{m}^3$ )
SO <sub>2</sub>	1-hour	29.45	917
	3-hour	20.62	786
	Annual	0.88	18
NO <sub>x</sub>	4-hour	128.22 <sup>1</sup>	3760
	8-hour	128.22 <sup>1</sup>	3760
	1-Month	19.23 <sup>2</sup>	564
	Annual	3.85	94
CO	1-Week	96.81 <sup>3</sup>	1,800,000

Notes:

<sup>1</sup> = 1-hour maximum NO<sub>x</sub> impact used

<sup>2</sup> = 24-hour maximum NO<sub>x</sub> impact used

<sup>3</sup> = 1-hour maximum CO impact used

#### G. Class I Analysis

Receptors were located in the following Class I areas:

- Great Gulf Wilderness Area/Dry River - Presidential Range (WMNF) 83 km WSW
- Moosehorn National Wildlife Refuge (MNWR) 240 km ENE
- Acadia National Park (ANP) 125 km E
- Roosevelt Campobello International Park (RCIP) 260 km ENE

The ISCST3 model, in simple and complex modes, using a five (5) year (1988-1992) meteorological database, was used to determine AELLC's maximum WMNF, MNWR and RCIP Class I increment impacts. For the WMNF Class I area, an addition year (1993) was modeled using ISCST3. For the ANP Class I area, the CALPUFF model, using a single year (1993) of specially processed multi-site meteorological data, was used to determine AELLC's maximum ANP Class I increment impacts.

Table IV-9 summarizes modeled impacts from the AELLC facility alone in Class I areas. All SO<sub>2</sub>, PM<sub>10</sub> and NO<sub>2</sub> (using Tier 2 approach) averaging period Class I increment impacts were below their respective significance levels (< 4% of Class I increment). Therefore, MEDEP-BAQ is convinced that emissions from the AELLC facility will not cause or contribute to any Class I increment violations.

**Table IV-9. Maximum Increment Consumption in Class I Areas from AELLC**

Pollutant/ Avg. Time	Maximum Impact ( $\mu\text{g}/\text{m}^3$ )	MODEL USED	Class I Receptor		Class I Significance*	Class I Increment ( $\mu\text{g}/\text{m}^3$ )
			Class I Area	Distance (km)		
SO <sub>2</sub> 3-hr	0.12	CALPUFF	ANP	150.7	1.0	25
	0.26	ISCST3	MNWR	242.4		
	0.15	ISCST3	RCIP	263.3		
	0.92	ISCST3	WMNF	95.6		
SO <sub>2</sub> 24-hr	0.05	CALPUFF	ANP	150.7	0.20	5
	0.04	ISCST3	MNWR	242.4		
	0.03	ISCST3	RCIP	263.3		
	0.17	ISCST3	WMNF	95.6		
SO <sub>2</sub> Annual	0.004	CALPUFF	ANP	150.7	0.08	1
	0.003	ISCST3	MNWR	239.4		
	0.002	ISCST3	RCIP	263.3		
	0.01	ISCST3	WMNF	95.6		
PM <sub>10</sub> 24-hr	0.04	CALPUFF	ANP	150.7	0.32	8
	0.04	ISCST3	MNWR	242.4		
	0.02	ISCST3	RCIP	262.2		
	0.14	ISCST3	WMNF	99.6		
PM <sub>10</sub> Annual	0.003	CALPUFF	ANP	150.7	0.16	4
	0.003	ISCST3	MNWR	239.4		
	0.002	ISCST3	RCIP	263.3		
	0.01	ISCST3	WMNF	95.6		
NO <sub>2</sub> Annual Tier 2	0.02	CALPUFF	ANP	150.7	0.10	2.5
	0.01	ISCST3	MNWR	239.4		
	0.01	ISCST3	RCIP	263.3		
	0.04	ISCST3	WMNF	95.6		

Notes:

\* = Proposed New Source Review Reform Class I significance levels.

#### H. Class I AQRV Analyses

**CLASS I VISIBILITY:** A VISCREEN Level-1 analysis was used to assess visibility impacts on Class I areas inside WMNF and ANP and Integral Vistas outside ANP. Visibility impacts on MNWR and RCIP Class I areas were not performed because the AELLC facility will be located at a distance well beyond 200 kilometers from those Class I areas. Table IV-10 summarizes the VISCREEN model input data for the Level-1 analysis. Data include source emission strengths for the facility, distances to the Class I areas, plume-observer angle, background visual range, model default values for meteorological conditions and background air quality levels.

**Table IV-10. VISCREEN Input Data**

POLLUTANT INPUT DATA			
Pollutant	Maximum Operating Case Emissions (g/s)		
Particulates	6.892		
NO <sub>x</sub> (as NO <sub>2</sub> )	36.22		
Primary NO <sub>2</sub>	0.00		
Soot	0.00		
Primary SO <sub>4</sub>	0.00		
DEFAULT PARTICLE CHARACTERISTICS			
Background Ozone	0.10 ppm		
Background Visual Range	60.00 km		
Plume-Source-Observer Angle	11.25°		
DISTANCE INPUT DATA			
	DISTANCE TO CLASS I AREAS		
Class I Area	Source-Observer Distance (km)	Minimum Source-Class I Distance (km)	Maximum Source-Class I Distance (km)
Great Gulf Wilderness Area/Dry River - Presidential Range	83.1	83.1	99.8
Acadia National Park	123.2	123.2	177.0

Results of the Level-1 analyses are summarized in Table IV-11. This table presents the worst-case plume perceptibility (Delta-E) and plume contrast values obtained for each situation analyzed. Level-1 screening results indicate that AELLC's proposed facility will not cause plume visibility impacts within Class I areas or their integral vistas. Because critical visibility values could be met using this method, no VISCREEN Level-2 or regional haze analyses were required.

**Table IV-11. VISCREEN Model Results in Class I Areas**

Level 1 Analysis						
			Inside Class I Area		Integral Vistas	
			Delta E	Contrast (±)	Delta E	Contrast (±)
CRITICAL VALUES			2.0	0.05	2.00	0.05
GREAT GULF/PRESIDENTIAL RANGE-DRY RIVER WILDERNESS AREAS						
Case	Background	Sun Angle	Delta E	Contrast (±)	Delta E	Contrast (±)
Maximum	Sky	10°	0.909	0.002	n/a	n/a
Maximum	Sky	140°	0.336	-0.007	n/a	n/a
Maximum	Terrain	10°	0.247	0.003	n/a	n/a
Maximum	Terrain	140°	0.059	0.002	n/a	n/a
ACADIA NATIONAL PARK						

Case	Background	Sun Angle	Delta E	Contrast (±)	Delta E	Contrast (±)
Maximum	Sky	10°	0.294	0.001	0.310	0.001
Maximum	Sky	140°	0.094	-0.003	0.098	-0.003
Maximum	Terrain	10°	0.059	0.001	0.076	0.001
Maximum	Terrain	140°	0.015	0.001	0.020	0.001

Note:

n/a = not applicable

**OTHER AQRV'S:** The Federal Land Managers for the ANP and WMNF Class I areas have identified the following additional AQRV's:

- wildlife, soils and vegetation (soils, vegetation and wildlife species in the park that are sensitive to ambient concentrations of pollutants.)
- water (sensitive watersheds where acid deposition is a problem.)
- odor (from reduced sulfur (RS) and total reduced sulfur (TRS) emissions)

Analyses of emission rates, ambient impacts and annual deposition rates were used to assess the potential impacts on those AQRV's. Qualitative analyses were only needed for AQRV's related to ozone and odor. Odor from the proposed project will not be a problem because emissions of RS and TRS will practically be non-existent and well below the 10 TPY de minimis levels.

Ozone is a secondary formed pollutant dependent on concentrations of NO<sub>x</sub> and VOC's and the intensity of sunlight. Sensitivity screening levels (EPA, December, 1980, EPA 450/2-81-078) for ozone are 0.20 ppmv for 1-hour, 0.10 ppmv for 3-hours and 0.06 ppmv for 8-hours. Expected periods of ozone concentrations above the sensitivity levels occur mainly with winds from the south to southwest. The AELLC facility will be located west of Acadia National Park Class I areas and east-northeast of WMNF Class I area, therefore AELLC emissions will not contribute to ozone damage to vegetative species during peak ozone concentration periods.

Quantitative analyses were used for AQRV's related to ambient impacts of SO<sub>2</sub>, NO<sub>2</sub> and CO emissions and dry deposition of SO<sub>2</sub> and NO<sub>2</sub>. Maximum ISCST3 (5-years) impacts in Tables IV-8 and IV-9 show that sensitive vegetation and soils in both Class I and Class II areas will not be adversely impacted by AELLC's SO<sub>2</sub>, NO<sub>2</sub> and CO emissions.

ISCST3 annual NO<sub>2</sub> and SO<sub>2</sub> dry deposition analyses were performed for the WMNF Class I area using a single year (1993) of specially processed on-site meteorological data. CALPUFF annual NO<sub>2</sub> and SO<sub>2</sub> total (dry and wet) deposition analyses were performed for the ANP Class I area using a single year (1993) of specially processed multi-site meteorological data. Results in Table IV-

12 shows that the maximum modeled yearly deposition rates at ANP and WMNF Class I areas are well below the USFS green line significance levels. Therefore, it is reasonably certain that AELLC NO<sub>2</sub> and SO<sub>2</sub> emissions will not significantly contribute to adverse impacts on soils, vegetation and sensitive watersheds in Class I areas.

**Table IV-12. AELLC Alone Dry Deposition in Class I Areas**

Class I Area	Pollutant	Model Used	Maximum AELLC Deposition (kg/ha-yr)	USFS Green Line Deposition Value* (kg/ha-yr)
Acadia National Park	SO <sub>2</sub>	CALPUFF	7.41 x 10 <sup>-4</sup>	5
	NO <sub>2</sub>		1.55 x 10 <sup>-3</sup> (wet + dry deposition)	5
Great Gulf Wilderness Area/Dry River - Presidential Range	SO <sub>2</sub>	ISCST3	3.89 x 10 <sup>-5**</sup>	5
	NO <sub>2</sub>		2.61 x 10 <sup>-4**</sup> (dry deposition only)	5

Note:

\* = from Table 6 of *Screening Procedure to Evaluate Effects of Air Pollution on Eastern Region Wilderness Cited as Class I Air Quality Areas* (Adams et al, 1991, Gen. Tech. Rep. NE-151, Radnor, PA; US Dept of Agriculture, Forest Service, Northeastern Forest Experiments Station)

\*\* = only dry deposition was analyzed.

## I. Summary

It has been demonstrated that AELLC's facility in its proposed configuration will not cause or contribute to a violation of any SO<sub>2</sub>, PM<sub>10</sub>, NO<sub>2</sub> or CO averaging period MAAQS. It has also been demonstrated that AELLC's facility in its proposed configuration will not cause or contribute to a violation of any SO<sub>2</sub>, PM<sub>10</sub>, or NO<sub>2</sub> averaging period Class I or Class II increment standards. In addition, AELLC's facility, in its proposed configuration will cause no impairment to AQRV's in Class I or II areas.

## ORDER

Based on the above Findings and subject to conditions listed below the Department concludes that the emissions from this source:

- will receive Best Practical Treatment,
- will not violate applicable emission standards,

- will not violate applicable ambient air quality standards in conjunction with emissions from other sources.

The Department hereby grants Air Emission License A-718-71-A-N subject to the following conditions:

**STANDARD CONDITIONS**

- (1) Employees and authorized representatives of the Department shall be allowed access to the licensee's premises during business hours, or any time during which any emissions units are in operation, and at such other times as the Department deems necessary for the purpose of performing tests, collecting samples, conducting inspections, or examining and copying records relating to emissions.
- (2) The licensee shall acquire a new or amended air emission license prior to commencing construction of a modification, unless specifically provided for in Chapter 115.
- (3) Approval to construct shall become invalid if the source has not commenced construction within eighteen (18) months after receipt of such approval or if construction is discontinued for a period of eighteen (18) months or more. The Department may extend this time period upon a satisfactory showing that an extension is justified, but may condition such extension upon a review of either the control technology analysis or the ambient air quality standards analysis, or both.
- (4) The licensee shall establish and maintain a continuing program of best management practices for suppression of fugitive particulate matter during any period of construction, reconstruction, or operation which may result in fugitive dust, and shall submit a description of the program to the Department upon request.
- (5) The licensee shall pay the annual air emission license fee to the Department, calculated pursuant to Title 38 MRSA §353.
- (6) The license does not convey any property rights of any sort, or any exclusive privilege.
- (7) The licensee shall maintain and operate all emission units and air pollution control systems required by the air emission license in a manner consistent with good air pollution control practice for minimizing emissions.

- (8) The licensee shall maintain sufficient records, to accurately document compliance with emission standards and license conditions and shall maintain such records for a minimum of six (6) years. The records shall be submitted to the Department upon written request.
- (9) The licensee shall comply with all terms and conditions of the air emission license. The filing of an appeal by the licensee, the notification of planned changes or anticipated noncompliance by the licensee, or the filing of an application by the licensee for the renewal of a license or amendment shall not stay any condition of the license.
- (10) The licensee may not use as a defense in an enforcement action that the disruption, cessation, or reduction of licensed operations would have been necessary in order to maintain compliance with the conditions of the air emission license.
- (11) In accordance with the Department's air emission compliance test protocol and 40 CFR Part 60 or other method approved or required by the Department, the licensee shall:
- A. perform stack testing to demonstrate compliance with the applicable emission standards under circumstances representative of the facility's normal process and operating conditions:
    - 1. within sixty (60) calendar days of receipt of a notification to test from the Department or EPA, if visible emissions, equipment operating parameters, staff inspection, air monitoring or other cause indicate to the Department that equipment may be operating out of compliance with emission standards or license conditions; or
    - 2. pursuant to any other requirement of this license to perform stack testing.
  - B. install or make provisions to install test ports that meet the criteria of 40 CFR Part 60, Appendix A, and test platforms, if necessary, and other accommodations necessary to allow emission testing; and
  - C. submit a written report to the Department within thirty (30) days from date of test completion.
- (12) If the results of a stack test performed under circumstances representative of the facility's normal process and operating conditions indicate emissions in excess of the applicable standards, then:

- A. within thirty (30) days following receipt of such test results, the licensee shall re-test the non-complying emission source under circumstances representative of the facility's normal process and operating conditions and in accordance with the Department's air emission compliance test protocol and 40 CFR Part 60 or other method approved or required by the Department; and
  - B. the days of violation shall be presumed to include the date of stack test and each and every day of operation thereafter until compliance is demonstrated under normal and representative process and operating conditions, except to the extent that the facility can prove to the satisfaction of the Department that there were intervening days during which no violation occurred or that the violation was not continuing in nature; and
  - C. the licensee may, upon the approval of the Department following the successful demonstration of compliance at alternative load conditions, operate under such alternative load conditions on an interim basis prior to a demonstration of compliance under normal and representative process and operating conditions.
- (13) Notwithstanding any other provision in the State Implementation Plan approved by the EPA or Section 114(a) of the CAA, any credible evidence may be used for the purpose of establishing whether a person has violated or is in violation of any statute, regulation, or Part 70 license requirement or PSD permit.
- (14) The licensee shall maintain records of malfunctions, failures, downtime, and any other similar change in operation of air pollution control systems or the emissions unit itself that would affect emissions and that is not consistent with the terms and conditions of the air emission license. The licensee shall notify the Department within two (2) days or the next state working day, whichever is later, of such occasions where such changes result in an increase of emissions. The licensee shall report all excess emissions in the units of the applicable emission limitation.
- (15) Upon the written request of the Department, the licensee shall establish and maintain such records, make such reports, install, use, and maintain such monitoring equipment, sample such emissions (in accordance with such methods, at such locations, at such intervals, and in such manner as the Department shall prescribe), and provide other information as the Department may reasonably require to determine the licensee's compliance status.

## **SPECIFIC CONDITIONS**

- (16) The following shall apply to the conditions in this order as appropriate, unless it is stated otherwise for such unit:
- A. A 24-hour block average basis shall be calculated as the arithmetic average of not more than 24 - one hour block periods. Only one 24-hour block average shall be calculated for one day, beginning at midnight.
  - B. A 3-hour block average basis shall be calculated as the arithmetic average of not more than 3 - one hour block periods. No more than eight 3-hour block averages shall be calculated for one day. One 3-hour block average shall be calculated for the period from midnight to 3:00, one from 3:00 to 6:00, one from 6:00 to 9:00, etc.
  - C. A 30-day rolling average basis shall be performed as described in 40 CFR Part 60, Subpart Db.
- (17) Cogeneration Systems #1, #2, and #3  
A Cogeneration System shall consist of a combustion turbine followed by a duct burner fired heat recovery steam generator (HRSG).
- A. Turbine #1, #2, #3
    - 1. The sulfur content of the fuel oil fired in Turbine #1, #2, or #3 shall not exceed 0.05% by weight demonstrated by purchase records from the supplier within the accuracy of the test methods used.
    - 2. No more than two of the Turbines #1, #2, and #3 shall be fired simultaneously with fuel oil.
    - 3. AELLC shall not operate the Turbines #1, #2, and #3 below the following load levels, except during startup, shutdown, or fuel transfer operations:
      - a. the respective electric load level of 50% based on the inlet air temperature, when firing natural gas; and
      - b. the respective electric load level of 65% based on the inlet air temperature, when firing fuel oil.
    - 4. AELLC shall not exceed a facility fuel use cap of 11,180,000 gallons/year of fuel oil with a maximum sulfur content not to exceed 0.05% by weight. AELLC shall demonstrate compliance with the facility fuel cap on a 12 month rolling total basis.

B. HRSG #1, #2, #3

1. Only natural gas may be fired in the duct burner fired HRSGs #1, #2, or #3.
2. AELLC shall not exceed a combined limit of  $2,637.2 \times 10^6$  standard cubic feet per year of natural gas to be fired in the three HRSGs #1, #2, and #3 on a 12 month rolling total basis.

C. Emissions from the Cogeneration Systems #1, #2, and #3 shall not exceed the following performance limits, except during startup, shutdown, or fuel transfer when they shall not exceed Condition (17)E.:

1. When firing natural gas in the HRSG and/or the Turbine:

Pollutant	Each Cogeneration System	Ave Time
NO <sub>x</sub>	6 ppmvd @15% O <sub>2</sub>	24 hr block ave

2. After 12 months from the date of initial performance testing, each Cogeneration System shall also demonstrate compliance with the following when firing natural gas in the HRSG and/or the Turbine:

Pollutant	Each Cogeneration System	Ave Time
NO <sub>x</sub>	4.5 ppmvd @15% O <sub>2</sub>	30 day rolling ave

3. When firing natural gas in the HRSG and/or firing fuel oil in the Turbine:

Pollutant	Each Cogeneration System	Ave Time
NO <sub>x</sub>	42 ppmvd @15% O <sub>2</sub>	3 hr block ave

4. The monitored NO<sub>x</sub> ppmvd emissions shall be met on a 24 hr block average basis, 30-day rolling average basis, and on a 3 hr block average basis as specified above in Condition (17)C.1., 2., and 3., depending on the fuel fired in the Cogeneration Systems.

- a. For each hour that fuel oil is fired in Turbine #1, #2, or #3, the monitored NO<sub>x</sub> ppmvd emissions shall not be included in determining compliance with the natural gas NO<sub>x</sub> ppmvd 30-day rolling and 24-hr block average emission limits specified in Condition (17)C.1. and 2., for that turbine that is firing fuel oil.

- b. For each hour that fuel oil is fired in Turbine #1, #2, or #3, the monitored NO<sub>x</sub> ppmvd emissions shall be used to comply with the emission limit of Condition (17)C.3., for that turbine that is firing fuel oil.
- c. Any portion of a block hour in which fuel oil is fired into a turbine shall be considered a monitored block hour ppmvd emission which shall be included in the average to demonstrate compliance with the fuel oil firing ppmvd limits.
- D. Emissions from each of the Cogeneration Systems #1, #2, and #3 shall not exceed the following limits, depending on the fuel type that is being fired in the respective Turbines and HRSGs, except during startup, shutdown, or fuel transfer when they shall not exceed Condition (17)E. below:

1. When firing natural gas in the HRSG and/or the Turbine:

Pollutant	lb/hr	Ave Time
PM	6.27	--
PM <sub>10</sub>	6.27	--
SO <sub>2</sub>	1.35	--
NO <sub>x</sub>	24.37	24 hr block ave
CO	74.21	24 hr block ave

Firing Natural Gas In	VOC (lb/hr)
Turbine Only	2.13
Turbine & HRSG	5.17

2. When firing natural gas in the HRSG and/or firing fuel oil in the Turbine:

Pollutant	lb/hr	Ave Time
PM	24.21	--
PM <sub>10</sub>	24.21	--
SO <sub>2</sub>	32.38	--
NO <sub>x</sub>	133.25	24 hr block ave
CO	43.73	24 hr block ave

Firing Natural Gas In	VOC (lb/hr)
Turbine Only	8.00
Turbine & HRSG	11.04

3. The monitored NO<sub>x</sub> and CO lb/hr emissions shall be met on a 24 hr block average basis as specified above in Condition (17)D., depending on the fuel fired during that calendar day.

For any portion of a calendar day in which fuel oil is fired into a turbine, the monitored NO<sub>x</sub> and CO lb/hr emissions for that calendar day shall be included in the average to demonstrate compliance with the fuel oil firing lb/hr limits, as appropriate, for that turbine firing fuel oil.

E. Turbine Startup, Shutdown, or Fuel Transfer

1. Emissions from each of the Cogeneration Systems #1, #2, or #3 shall not exceed the following limits during startup, shutdown, or fuel transfer while firing natural gas or fuel oil, except for the first 12 months after the initial performance testing when they shall be exempt:

Pollutant	lb/hr	Ave Time
PM	24.21	--
PM <sub>10</sub>	24.21	--
SO <sub>2</sub>	32.38	--
NO <sub>x</sub>	133.25	24 hr block ave
CO	74.21	24 hr block ave
VOC	36.10	--

2. The monitored NO<sub>x</sub> and CO lb/hr emissions shall be demonstrated on a 24 hr block average basis and shall not exceed the specified limits of Condition (17)E.1. above, for each Cogeneration System that is operating in a startup, shutdown, or fuel transfer mode.

Any portion of a calendar day in which a turbine startup, shutdown, or fuel transfer has occurred shall be considered monitored NO<sub>x</sub> and CO lb/hr emissions which shall be included in the average to demonstrate compliance with the turbine startup, shutdown, or fuel transfer lb/hr limits, as appropriate, for that turbine which has had a turbine startup, shutdown, or fuel transfer.

3. A fuel transfer mode shall be defined as the period of time during which the fuel fired in the turbine is switched from oil to gas or gas to oil. This period shall not exceed 30 minutes.

4. The period allowed for a turbine startup shall be defined as that period of time from initiation of combustion turbine firing until the unit reaches steady state operation at a load between 50% and 100% load conditions. This period shall not exceed 60 minutes for a hot start, nor 180 minutes for a cold start. A cold start shall be defined as startup when the turbine has been down for more than 24 hours.
5. The period allowed for a turbine shutdown shall be defined as that period of time from when fuel is begun to be removed from the turbine for the purpose of shutting down the unit and not to exceed 180 minutes.
- F. A continuous emission monitor system (CEMS) shall be installed and operated to monitor NO<sub>x</sub> and CO ppmvd and lb/hr emissions and O<sub>2</sub> concentration of each Cogeneration System #1, #2, and #3. Each monitor shall meet the criteria of the appropriate performance specification of 40 CFR Part 60 Appendix B and Part 75.
- G. AELLC shall monitor and record the NO<sub>x</sub> lb/hr and ppmvd emissions and the CO lb/hr emissions on an hourly basis separately for those conditions when fuel oil or natural gas is fired within the respective turbines and separately for those periods when the unit is in a startup, shutdown, and fuel transfer mode. AELLC shall also monitor and record the average of the hourly values as applicable.
- H. A continuous emission monitor system (CEMS) shall be installed and operated to monitor ammonia (NH<sub>3</sub>) ppmvd emissions of each Cogeneration System #1, #2, and #3.
- I. The monitored ammonia (NH<sub>3</sub>) emissions from each of the Cogeneration Systems #1, #2, and #3 shall not exceed 10 ppmvd @15% O<sub>2</sub> on a 24 hr block average basis.
- J. The particulate emissions from each of the Cogeneration Systems #1, #2, and #3 shall not exceed 0.06 lb/MMBtu.
- K. The nitrogen oxide emissions from each of the duct burner fired HRSGs #1, #2, and #3 alone shall not exceed 0.14 lb/MMBtu. Compliance with this limit shall be by calculating the difference in the results of the tested or monitored NO<sub>x</sub> lb/MMBtu emissions, with and without the HRSGs operating.

- L. The exhaust from each Cogeneration System #1, #2 or #3 shall be vented through separate flues to the three closely bundled separate stacks which will be at least 212 feet tall above ground level.
- M. Visible emissions from each stack shall not exceed 20% opacity, measured as 6 minute averages, except for one 6 minute average period per hour of not more than 27% opacity.
- N. AELLC shall operate each of the:
1. Turbines #1, #2, and #3 with:
    - a. Low NO<sub>x</sub> Combustors for NO<sub>x</sub> emission control; and
    - b. with water injection during the firing of fuel oil for NO<sub>x</sub> emission control.
  2. duct burner fired HRSGs #1, #2, and #3 with Low NO<sub>x</sub> Burners for NO<sub>x</sub> emission control.
  3. Cogeneration Systems #1, #2, and #3 with:
    - a. Selective Catalytic Reduction (SCR) Systems for NO<sub>x</sub> emission control; and
    - b. a Catalyst for CO emission control.The respective SCR System does not have to operate during the firing of fuel oil and during a turbine startup, shutdown and fuel transfer.

The emission control systems as mentioned in this condition shall be operated in accordance with Condition (9).

- O. AELLC shall monitor and record the following as specified, for each Cogeneration System #1, #2, and #3:

<b>Parameter for each Cogeneration System</b>	<b>Monitor</b>	<b>Record</b>
turbine fuel oil firing rate	continuously	continuously
turbine natural gas firing rate	continuously	continuously
water injection rate	continuously	continuously
HRSG natural gas firing rate	continuously	continuously
electric load level	continuously	continuously
turbine air inlet temperature	continuously	continuously

The parameter monitors shall be properly maintained, calibrated, and operated at all times the source or process being monitored is operating except for

outages not exceeding five percent (5%) of the source operating time on a quarterly basis which are attributable to QA/QC activities, sudden, unforeseen equipment malfunctions or failure not associated with operator error, poor maintenance or any other reasonably preventable condition.

- P. The fuel oil fired into each Turbine #1, #2, and #3 shall be monitored by a fuel flow monitor operated in accordance with the manufacturers specifications.
- (18) Pursuant to 40 CFR, Part 60, Subpart GG, Turbines #1, #2, and #3 are subject to the following:
- A. AELLC shall continuously monitor and record the fuel consumption and the ratio of water to fuel oil being fired into each of the turbines on an hourly block average basis. Records shall be maintained according to Condition (8) and 40 CFR Part 60, Subpart GG.
- B. AELLC shall monitor the fuel-bound nitrogen and sulfur content of the natural gas and fuel oil as described in 40 CFR, Part 60, Subpart GG or by a frequency as approved by the Administrator. Records shall be maintained according to Condition (8).
- (19) Performance Tests
- AELLC shall conduct the following initial performance tests within 60 days after achieving the maximum production rate at which the plant will be operated but not later than 180 days after the initial startup. All testing shall comply with all of the requirements of the DEP Compliance Test Protocol and with 40 CFR Part 60, as appropriate, or other methods or testing scenarios approved by the Bureau of Air Quality. A representative of the DEP or Environmental Protection Agency (EPA) shall be given the opportunity to observe the compliance testing.

A. Pursuant to 40 CFR, Part 60, Subpart GG:

	<b>Pollutant</b>	<b>Limit</b>	<b>Unit/ Fuel</b>	<b>Operation Scenarios</b>	<b># of Tests</b>	<b>EPA Method</b>
1.	NOx	42 ppmvd @15% O <sub>2</sub>	Turbine #1/ oil HRSG #1/ gas	Turbine #1 @ 100% load HRSG #1 @ 100% load	1	20
2.	NOx	42 ppmvd @15% O <sub>2</sub>	Turbine #1/ oil	Turbine #1 @ three load levels between 65% and 100%	3	20
3.	NOx	42 ppmvd @15% O <sub>2</sub>	Turbine #2/ oil HRSG #2/ gas	Turbine #2 @ 100% load HRSG #2 @ 100% load	1	20
4.	NOx	42 ppmvd @15% O <sub>2</sub>	Turbine #2/ oil	Turbine #2 @ three load levels between 65% and 100%	3	20

5.	NOx	42 ppmvd @15% O <sub>2</sub>	Turbine #3/ oil HRSG #3/ gas	Turbine #3 @ 100% load HRSG #3 @ 100% load	1	20
6.	NOx	42 ppmvd @15% O <sub>2</sub>	Turbine #3/ oil	Turbine #3 @ three load levels between 65% and 100%	3	20
7.	NOx	6 ppmvd @15% O <sub>2</sub>	Turbine #1/ gas HRSG #1/ gas	Turbine #1 @ 100% load HRSG #1 @ 100% load	1	20
8.	NOx	6 ppmvd @15% O <sub>2</sub>	Turbine #1/ gas	Turbine #1 @ three load levels between 65% and 100%	3	20
9.	NOx	6 ppmvd @15% O <sub>2</sub>	Turbine #2/ gas HRSG #3/ gas	Turbine #2 @ 100% load HRSG #2 @ 100% load	1	20
10.	NOx	6 ppmvd @15% O <sub>2</sub>	Turbine #2/ gas	Turbine #2 @ three load levels between 65% and 100%	3	20
11.	NOx	6 ppmvd @15% O <sub>2</sub>	Turbine #3/ gas HRSG #3/ gas	Turbine #3 @ 100% load HRSG #3 @ 100% load	1	20
12.	NOx	6 ppmvd @15% O <sub>2</sub>	Turbine #3/ gas	Turbine #3 @ three load levels between 65% and 100%	3	20

**B. Pursuant to 40 CFR, Part 60, Subpart Db:**

	<b>Pollutant</b>	<b>Limit</b>	<b>Unit/ Fuel</b>	<b>Operation Scenarios</b>	<b># of Tests</b>	<b>EPA Method</b>
1.	NOx	0.15 lb/MMBtu	Turbine #1/ oil HRSG #1/ gas	Turbine #1 @ 100% load HRSG #1 @ 100% load	1	20
			Turbine #1/ oil	Turbine #1 @ 100% load	1	20
2.	NOx	0.15 lb/MMBtu	Turbine #2/ oil HRSG #2/ gas	Turbine #2 @ 100% load HRSG #2 @ 100% load	1	20
			Turbine #2/ oil	Turbine #2 @ 100% load	1	20
3.	NOx	0.15 lb/MMBtu	Turbine #3/ oil HRSG #3/ gas	Turbine #3 @ 100% load HRSG #3 @ 100% load	1	20
			Turbine #3/ oil	Turbine #3 @ 100% load	1	20
4.	PM	0.06 lb/MMBtu	Turbine #1/ oil HRSG #1/ gas	Turbine #1 @ 100% load HRSG #1 @ 100% load	1	5B
5.	PM	0.06 lb/MMBtu	Turbine #2/ oil HRSG #2/ gas	Turbine #2 @ 100% load HRSG #2 @ 100% load	1	5B
6.	PM	0.06 lb/MMBtu	Turbine #3/ oil HRSG #3/ gas	Turbine #3 @ 100% load HRSG #3 @ 100% load	1	5B

**C. For BACT, AELLC:**

	<b>Pollutant</b>	<b>Limit</b>	<b>Unit/ Fuel</b>	<b>Operation Scenarios</b>	<b># of Tests</b>	<b>EPA Method</b>
1.	VOC	8.00 lb/hr	Turbine #1/ oil	Turbine #1 @ four load levels between 65% and 100%	4	18 and 25

2.	VOC	8.00 lb/hr	Turbine #2/ oil	Turbine #2 @ four load levels between 65% and 100%	4	18 and 25
3.	VOC	8.00 lb/hr	Turbine #3/ oil	Turbine #3 @ four load levels between 65% and 100%	4	18 and 25
4.	VOC	11.04 lb/hr	Turbine #1/ oil HRSG #1/ gas	Turbine #1 @ 100% load HRSG #1 @ 100% load	1	18 and 25
5.	VOC	11.04 lb/hr	Turbine #2/ oil HRSG #2/ gas	Turbine #2 @ 100% load HRSG #2 @ 100% load	1	18 and 25
6.	VOC	11.04 lb/hr	Turbine #3/ oil HRSG #3/ gas	Turbine #3 @ 100% load HRSG #3 @ 100% load	1	18 and 25
7.	VOC	2.13 lb/hr	Turbine #1/ gas	Turbine #1 @ four load levels between 65% and 100%	4	18 and 25
8.	VOC	2.13 lb/hr	Turbine #2/ gas	Turbine #2 @ four load levels between 65% and 100%	4	18 and 25
9.	VOC	2.13 lb/hr	Turbine #3/ gas	Turbine #3 @ four load levels between 65% and 100%	4	18 and 25
10.	VOC	5.17 lb/hr	Turbine #1/ gas HRSG #1/ gas	Turbine #1 @ 100% load HRSG #1 @ 100% load	1	18 and 25
11.	VOC	5.17 lb/hr	Turbine #2/ gas HRSG #2/ gas	Turbine #2 @ 100% load HRSG #2 @ 100% load	1	18 and 25
12.	VOC	5.17 lb/hr	Turbine #3/ gas HRSG #3/ gas	Turbine #3 @ 100% load HRSG #3 @ 100% load	1	18 and 25

Note: The turbine load levels represent the respective electric load levels based on the inlet air temperatures.

- (21) AELLC shall install test ports in each flue to the stacks #1, #2, and #3, in accordance with the criteria of EPA Test Method One, and test platforms, if necessary, to allow emission compliance testing of each of the Cogeneration Systems #1, #2, and #3.
- (22) AELLC shall submit to the Bureau of Air Quality, 60 days prior to startup, for approval, a report indicating how compliance with the lb/hr CEMS emission limits shall be performed.
- (23) Cogeneration Systems #1, #2, and #3 are subject to 40 CFR Part 60 Subparts A, D, Db, and GG, as appropriate and AELLC shall comply with the notification and recordkeeping requirements of 40 CFR Part 60.7.
- (24) For Compliance Assurance, AELLC shall comply with the following:  
The Bureau of Air Quality finds the following Compliance Assurance Plan to be reasonable and appropriate.

**A. Quarterly Reporting**

1. The licensee shall submit a Quarterly Report to the Bureau of Air Quality within 30 days after the end of each calendar quarter, detailing the following, for the Control Equipment, Parameter Monitors, Continuous Emission Monitoring Systems (CEMS) required by this license:
  - a. All control equipment downtimes and malfunctions;
  - b. All CEMS downtimes and malfunctions;
  - c. All downtimes of the above specified parameter monitors;
  - d. All excess events of emission and operational limitations set by this Order, statute, state or federal regulation, as appropriate; and
  - e. A report certifying there were no excess emissions, if that is the case.
2. The following information shall be reported for each excess event:
  - a. Standard exceeded;
  - b. Date, time, and duration of excess event;
  - c. Maximum and average values of the excess event, reported in the units of the applicable standard, and copies of pertinent strip charts and print-outs when requested;
  - d. A description of what caused the excess event;
  - e. The strategy employed to minimize the excess event;
  - f. The strategy employed to prevent reoccurrence; and

**B. Record-Keeping**

1. For all of the equipment parameter monitoring and recording, required by this license, the licensee shall maintain records of the most current six year period and the records shall include:
  - a. Documentation which shows monitor operational status during all source operating time, including specifics for calibration and audits; and
  - b. A complete data set of all monitored parameters as specified in this license. All parameter records shall be made available to the Bureau of Air Quality upon request.
2. The CEMS required by this license shall be the primary means of demonstrating compliance with emission standards set by this Order, statute, state or federal regulation, as applicable. For all CEMS, the licensee shall maintain records of the most current six year period and the records shall include:
  - a. Documentation that all CEMS are continuously accurate, reliable and operated in accordance with Chapter 117; and

- b. Upon the written request by the Department, a report or other data indicative of compliance with the applicable emission standard for those periods when the CEMS were not in operation or produced invalid data. In the event the Bureau of Air Quality does not concur with the licensee's compliance determination, the licensee shall, upon the Bureau of Air Quality's request, provide additional data, and shall have the burden of demonstrating that the data is indicative of compliance with the applicable standard.

C. Stack Testing

1. The licensee shall conduct emission testing, and demonstrate compliance with the applicable standard within 60 days after receipt of notice from the Bureau of Air Quality:
2. The licensee shall conduct particulate emission testing and demonstrate compliance at least once every two years on the following:

	Pollutant	Limit	Unit/ Fuel	Operation Scenarios	# of Tests	EPA Method
a.	PM	0.06 lb/MMBtu	Turbine #1/ oil HRSG #1/ gas	Turbine #1 @ 100% load HRSG #1 @ 100% load	1	5B
b.	PM	0.06 lb/MMBtu	Turbine #2/ oil HRSG #2/ gas	Turbine #2 @ 100% load HRSG #2 @ 100% load	1	5B
c.	PM	0.06 lb/MMBtu	Turbine #3/ oil HRSG #3/ gas	Turbine #3 @ 100% load HRSG #3 @ 100% load	1	5B

Note: The turbine load levels represent the respective electric load levels based on the inlet air temperatures.

AELLC may apply to amend the license to reduce the frequency of stack testing or to test only one cogeneration system upon successful compliance demonstration of two consecutive stack tests (i.e. the first upon startup and the second two years after startup).

3. All testing programs shall comply with all of the requirements of the DEP Compliance Test Protocol and with 40 CFR Part 60, as appropriate, or other methods approved by the Bureau of Air Quality.

(25) This term of this license shall be five years from the signature date below.

ANDROSCOGGIN ENERGY LIMITED )  
LIABILITY COGENERATION CENTER )  
FRANKLIN COUNTY )  
JAY, MAINE )  
A-718-71-A-N )  
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DEPARTMENT  
FINDINGS OF FACT AND ORDER  
AIR EMISSION LICENSE

DONE AND DATED IN AUGUSTA, MAINE THIS DAY OF 1998.

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BY: \_\_\_\_\_  
EDWARD O. SULLIVAN, COMMISSIONER

PLEASE NOTE THE ATTACHED SHEET FOR GUIDANCE ON APPEAL PROCEDURES

Date of initial receipt of application September 12, 1997

Date of application acceptance September 12, 1997

Date filed with the Board of Environmental Protection \_\_\_\_\_

This Order prepared by Kim Hibbard, Bureau of Air Quality